FONDAZIONE ENI ENRICO MATTEI

NOTA DI LAVORO

60.2016

Investing in Photovoltaics: Timing, Plant Sizing and Smart Grids Flexibility

Marina Bertolini, University of Padova and Centro Studi "Giorgio Levi Cases"
Chiara D'Alpaos, University of Padova and Centro Studi "Giorgio Levi Cases"
Michele Moretto, University of Padova, Fondazione Eni Enrico Mattei (FEEM) and Centro Studi "Giorgio Levi Cases"

Mitigation, Innovation and Transformation Pathways
Series Editor: Massimo Tavoni

Investing in Photovoltaics: Timing, Plant Sizing and Smart Grids Flexibility

By Marina Bertolini, University of Padova and Centro Studi "Giorgio Levi Cases"
Chiara D'Alpaos, University of Padova and Centro Studi "Giorgio Levi Cases"
Michele Moretto, University of Padova, Fondazione Eni Enrico Mattei (FEEM) and Centro Studi "Giorgio Levi Cases"

Summary

In Italy and in many EU countries, the last decade was characterized by a large development of distributed generation power plants. Their presence determined new critical issues for the design and management of the overall energy system and the electric grid due to the presence of discontinuous production sources. It is commonly agreed that contingent problems that affect local grids (e.g. inefficiency, congestion rents, power outages, etc.) may be solved by the implementation of a "smarter" electric grid. The main feature of smarts grid is the great increase in production and consumption flexibility. Smart grids give producers and consumers, the opportunity to be active in the market and strategically decide their optimal production/consumption scheme. The paper provides a theoretical framework to model the prosumer's decision to invest in a photovoltaic power plant, assuming it is integrated in a smart grid. To capture the value of managerial flexibility, a real option approach is implemented. We calibrate and test the model by using data from the Italian energy market.

Keywords: Smart Grids, Renewable Energy Sources, Real Options, Prosumer

JEL Classification: Q42, C61, D81

We acknowledge financial support by the University of Padova under the project CPDA133332/13.

Address for correspondence:
Michele Moretto
University of Padova
Via del Santo, 33
35100 Padova
Italy
E-mail: michele.moretto@unipd.it

Investing in photovoltaics: timing, plant sizing and smart grids flexibility*

Marina Bertolini[†], Chiara D'Alpaos[‡], and Michele Moretto[§]

8 August 2016

Abstract

In Italy and in many EU countries, the last decade was characterized by a large development of distributed generation power plants. Their presence determined new critical issues for the design and management of the overall energy system and the electric grid due to the presence of discontinuous production sources. It is commonly agreed that contingent problems that affect local grids (e.g. inefficiency, congestion rents, power outages, etc.) may be solved by the implementation of a "smarter" electric grid.

The main feature of smarts grid is the great increase in production and consumption flexibility. Smart grids give producers and consumers, the opportunity to be active in the market and strategically decide their optimal production/consumption scheme. The paper provides a theoretical framework to model the prosumer's decision to invest in a photovoltaic power plant, assuming it is integrated in a smart grid. To capture the value of managerial flexibility, a real option approach is implemented. We calibrate and test the model by using data from the Italian energy market.

JEL: Q42; C61; D81

Keywords: Smart Grids, Renewable Energy Sources, Real Options, Prosumer

1 Introduction

Growing concern about GHG emissions and future availability of traditional energy sources motivated national governments to promote renewable energy distributed generation. In Italy, the last decade was characterized by a large development of distributed generation power plants, mostly biomass and photovoltaic power plants: private investments in these sectors were boosted through incentives, that made them particularly attractive for both institutional investors and (small) private investors. Distributed generation plants, increased grid and systems costs in terms of proper managing of network congestions for needs of continuous real time balancing. The increasing number of investments in photovoltaic (PV) power plants, as other discontinuous and distributed energy production sources, generated problems that affected local grids (e.g. inefficiency, congestion rents, power outages, etc.), part of which might be solved by the implementation of a "smarter" electric grid. The efficient integration of these renewable sources requires in fact large infrastructure

*We acknowledge financial support by the University of Padova under the project CPDA133332/13.

[†]Department of Department of Civil, Architectural and Environmental Engineering, University of Padova, Padova (Italy), and Centro Studi "Giorgio Levi Cases".

[‡]Department of Civil, Architectural and Environmental Engineering, University of Padova, Padova (Italy), and Centro Studi "Giorgio Levi Cases".

[§]Department of Economics and Management, University of Padova, Padova (Italy), Fondazione Eni Enrico Mattei (FEEM), and Centro Studi "Giorgio Levi Cases"

investments in new electricity generation, transmission and demand, as well as flexible management of the system, that are characterized by high irreversibility and uncertainties over demand evolution, technological advances, and an ever changing regulatory environment (Schachter and Mancarella, 2015). Smart Grids (SGs) represent de facto the evolution of electrical grids and their implementation is challenging the electric market organization and management. SGs allow for an instantaneous interaction between agents and the grid: depending on its needs, the grid can send signals (through prices) to the agents, and the agents have the possibility to respond to those signals and obtain a monetary gain as a counterpart. In this way, the system can allow for better integration of renewables – that in turn contribute to keep the grid stable - and for photovoltaic development in the absence of costly monetary incentives.

In this paper we investigate whether the connection to a SG can increase the investment value in a PV plant (i.e. the investment profitability) and influence the decision on the plant's optimal size. We model the investment decision of a small (price taker) household end-user, that is simultaneously a consumer and a producer, i.e. a prosumer (Toffler, 1980; Karnouskos, 2011; Da Silva *et al.*2014; Kastel and Gilroy-Scott, 2015)[1]. We provide and implement a Real Option model to determine the overall investment value of a PV system where a prosumer, connected to a local energy market via a SG, can contribute to real time balancing of the electric system and, in this way, to be paid for the reduction of network imbalance costs. In the specific, as a consumer, he can buy energy from the national grid at a fixed contractual price or self-consume the energy produced by the PV plant; as a producer he may decide to collaborate with the local energy market manager to grid equilibrium, by selling the energy produced.

In this respect, SGs may generate managerial flexibilities that prosumers can optimally exercise when deciding to invest. This flexibility gives a prosumer the option to strategically decide the optimal production/consumption energy pattern and can significantly contribute to energy saving and hedging the investment risk. That is, if optimally exercised, operational flexibility can be economically relevant and its value is strongly related to the prosumer ability to decide his investment strategy and planned course of action in the future, given then-available information[2].

Traditional capital budgeting techniques fail to capture the value of this managerial flexibility. It is widely recognized that the Net Present Value rule fails because it cannot properly capture managerial flexibility to adapt and revise later decisions in response to unexpected market events. As new information arrives and uncertainty about future cash flows is gradually resolved, management may have valuable flexibility to alter its initial operating strategy in order to capitalize on favorable future opportunities (Majd and Pindyck, 1987; Triantis and Hodder, 1991; Dixit and Pindyck, 1994; Trigeorgis, 1996; D'Alpaos *et al.* 2006; D'Alpaos *et al.*, 2013).

We base our analysis on two main tested hypotheses. Our findings show that the possibility to sell energy via the SG, increases the investment value. The connection to the SG increases managerial flexibility: the agent can optimally exercise the option to decide the prosumption quota and switch from prosumption to production, thus increasing the investment value. Furthermore the opportunity to sell energy favours the agent to invest in a plant of bigger size if compared to the one needed for self-consumption and there exists a positive relation between the optimal size and the (optimal) investment timing.

By combining irreversible investment under uncertainty with the connection to a SG, our paper mainly contributes to two strands of literature. First and more broadly speaking, our model

[1] While referring to the prosumer, we will use prosumption to identify production with the consequent consumption of the energy produced by the prosumer himself, and the verb to prosume to express prosumer's activity.

[2] The concept of grid parity where the cost of self-produced energy is equal to electricity from the power grid can be a catalyst for change in energy markets, particularly when energy can be self-consumed (Biondi and Moretto, 2015).

contributes to the literature on distributed generation, SG technologies and prosumers behaviour in energy markets (Hoff *et al.* 1996; Olsina *et al.*, 2006; Fleten *et al.,* 2007; Shi and Qu X, 2011; Ottesen *et al.*, 2016) that suggests solutions to grid congestion and enhancement of the ability of the system to accommodate intermittent renewables (Konstantelos and Strbac, 2015) such as storage (Lamont, 2013; Poudineh and Jamasb, 2014), demand-side management (Ore, 2001) and demand-response (Sezgen *et al.*, 2007; Shaw *et al.*, 2010; Martinez Cesena and Mancarella, 2014; Schachter and Mancarella, 2015; Syrri and Mancarella, 2016). Second, we complement the existing literature on the Real Options approach to investment decisions in the energy sector (Fleten *et al.* , 2007; Fernandes *et al.*, 2011; Martinez Cesena *et al.*, 2013; Capuder and Mancarella, 2014; Wang *et al.* 2014) and the evaluation of investment flexibility in SGs (Schachter and Mancarella, 2016) with a novel application to prosumer's flexible investment decisions in PV systems.

Among these contributions, the closest to ours is Sezgen *et al.* (2007) where the authors use methodologies developed for pricing equity and commodity derivatives to estimate the value of demand-response technologies that generates opportunities for end-users to alter their demand in response to electric system reliability needs or high prices. Demand-response strategies can be considered as Real Options where the end-users have the right but not the obligation to alter the operating schedule for loads. In Sezgen *et al.* (2007) end-users can observe day-ahead market hourly prices and decide subsequently whether to shift or curtail loads during on-peak hours the next day. They show that there are in fact significant benefits to the electric system if customers are willing to curtail their loads and/or be dispatched by independent system operators via the implementation of demand response programs in which customers bid load curtailments into day-ahead or real-time markets.

Differently from Sezgen *et al.* (2007), in our model the prosumer, can optimally exercise at any time the option to decide the self-consumption quota or energy injection in the network according to the selling price. Our reaserch question is therefore whether the connection to a SG that increases de facto the prosumer's managerial flexibility is able to boost investments in PV systems in the absence of incentives. At the end, to capture the value of managerial flexibility, we calibrate and test our model by using data from the Italian energy market.

The paper remainder is organized as follows. Section 2 describes the model set up. Section 3 and 4 provide the model to determine the PV investment value and the optimal investment size and timing respectively. Section 5 introduces the model parameter estimations from empirical data driven from the Italian electricity market; Section 6 provides simulations and sensitivity analyses to calibrate the model and illustrate theoretical results. Section 7 concludes.

2 Model set up

We consider an agent currently connected to a national grid under a flat contract that has to decide whether and when to invest in a PV plant to cover part of his demand of energy. Although this decision has as primary target his electricity consumption, he may also decide to connect the plant, through a SG, to a local energy market with the possibility of selling, totally or partially, the energy produced. In the specific, we consider the case where he can decide to collaborate with the local market operator (or manager) to grid equilibrium, i.e to reduce network imbalance costs, by selling energy.

Before analysing the investment decision, let's introduce some simplifying assumptions:

Assumption 1 The agent's demand of energy per unit of time t is normalized to 1 (i.e. 1 MWh).

The energy demand can be represented as follows:

$$1 = \xi\alpha_1 + \alpha_2 \tag{1}$$

where $\alpha_1 > 0$ is the "expected"[3] production of the power plant per unit of time, $\xi \in [0, 1]$ is the production quota used for self-consumption[4] and $0 < \alpha_2 \leq 1$ is the energy quota bought from the national grid.

Considering a day (i.e. 24 hours) as unit measure of time, $\xi\alpha_1 + \alpha_2 \equiv \int_0^{24} l(s)ds = 1$ where $l(s)$ denotes the consumption of energy at time $s \in [0, 24]$. In this case α_2 is the energy quota that must necessarily be bought from the national grid, since it satisfies energy demand during the time interval of plant inactivity (i.e. when solar radiations are not available), whereas $\xi\alpha_1$ is the energy self-consumed when the plant is in operation. This also implies that $(1 - \xi)\alpha_1$ is the "expected" production the agent can sell on the local energy market.

Assumption 2 Storage is not possible.

This is consistent with $\alpha_2 > 0$. In other words, no batteries are included in the PV plant. This reduces the agent's managerial flexibilities, since energy must be used as long as it is produced[5].

Assumption 3 The agent receives information on the selling price at the beginning of each time interval t and, on the basis of this information, he makes the decision on how much of the produced energy to consume and how much to sell in the local market.

In other words, for sake of simplicity, we are assuming that there is only one hourly local spot market where the agent observes the selling price and decides a that point either to sell the entire production or not.[6]

Assumption 4 The agent cannot buy energy from the local market.

This is a crucial assumption. Although, the possibility that agents produce energy and inject it in the grid is actually one of the reasons for implementing SG tecnologies (Lund *et al.* 2012; Maarten, 2012; Pillai *et al.* 2011), here we assume that the reverse is not possible. The local market we are considering is not for direct consumption but for the general magagement and control of the electric system (i.e the ancillary services market). Since there are events where demand for power is higher than supply the agent may be called for being active in the market and increasing the level of reliability of the system by selling part of the energy he produces. This helps to reduce system costs caused by unpredictable energy inflows coming from distributed and non-dispatchable energy sources, and this in turn makes more challenging activities related to system-balancing.

[3] As the production of PV system depends, among others, on: i) the geographic positions (i.e. latitude and longitude); ii) climate and atmospheric conditions; iii) and stagionality, the parameter α_1 in (1) indicates the average production per unit of time. This includes losses due to temperature and low irradiance, losses due to shading and albedo as well as other losses due to deterioration of cables and inverter.

[4] The agent's self-consumption level depends on his individual load profile, the location and the renewable energy technology applied (Velik and Nikolay, 2015; Pillai *et al.*, 2014).

[5] We leave to further research the analysis on investigating the investment decision in the presence of batteries, that generates new investment opportunities for the producer. See Mulder *et al.* (2010) for a case study of optimal storage size for a grid-connected PV plant.

[6] In general the agent observes the day-ahead market price and decides at that point either to sell or not the energy next day. Since we work in continuos time, we assume that the response is istantaneous.

Information on grid needs are delivered through the buying price to solve balancing needs, local congestions or sudden black outs.

Since the agent's objective is to minimize energy costs, the investment decision will depend on his energy demand and on the ratio between the buying and selling price of energy. Then, according to Assumptions 1-4, indicating by c the fixed contract price (buying price) of energy, a the per unit cost paid to produce energy by the PV plant and v the selling price of energy, we can write the agent's net cost of energy per unit of time as follows:

$$\begin{aligned} C &= \min\left[c-\alpha_1(v-a), \quad \xi\alpha_1 a+(1-\xi\alpha_1)c-(1-\xi)\alpha_1(v-a)\right] \\ &\equiv c-\alpha_1(v-a)+\min[\xi\alpha_1(v-c), \quad 0] \end{aligned} \tag{2}$$

The first term inside the square bracket is the net cost in the absence of self-consumption (i.e. energy is totally sold in the market), the second term indicates the net cost in the presence of self-consumption. Note that the energy costs paid by the agent depend on the possibility of choosing between selling energy in the market or self-consuming. In the former case, he pays c and earns $\alpha_1 v$, minus the cost of producing α_1, and sells the energy quota produced by the plant in the local market. In the latter case, part of the energy produced is consumed ($\xi\alpha_1$), and part ($\alpha_2 = 1-\xi\alpha_1$), is bought at the contract fixed price c while the energy produced but not consumed is sold in the local market at price v.

Though SGs allow for istantaneous exchange of energy flows and information on energy prices, due to the small dimension of our agent, it is reasonable to assume that he cannot rapidly change his consumption pattern $l(s)$. In particular:

Assumption 5 The quota of energy demand that the agent is able to satisfy through the production of the plant is rigid, i.e. $\bar{\alpha} = \xi\alpha_1 < 1$.

This simplifies the analysis and does not seem overly restrictive. Although households energy management is widely recognized[7] as a priority to reach an overall cost-saving by PV generation systems, nowadays consumers' load during the day is still particularly high in the evening[8], while the quota of energy consumed in the morning and/or in the afternoon is still quite low. Then, having normalized the energy demand to one, by fixing $\bar{\alpha}$ the production quota used for self-consumption ξ is endogenously determined once the plant size α_1 is chosen[9]. Active households energy management may increase $\bar{\alpha}$, this in turn may induce investors to install greater size plants.

Finally, we assume that the buying price c is constant over time and the marginal cost of internal production is null, i.e. $a = 0$[10]. Whereas, the selling price v is stochastic and driven by the following Geometric Brownian Motion:

$$dv(t) = \gamma v(t)dt + \sigma v(t)dz(t) \qquad \text{with } v(0) = \nu_0 \tag{3}$$

where $dz(t)$ is the increment of a Wiener process, σ is the istanataneous volatility and γ is the drift term lower than the market (i.e. risk adjusted) discount rate r, i.e. $\gamma \leq r$[11]. Equation (3)

[7] See Ciabattoni *et al.* (2014) among others.

[8] According to the analysis performed by the Italian National Authority for Electricity, Gas and Water Services (AEEGSI) in 2009, the higher peak load demanded by residential users occurs in the evening, between 8:00 p.m. and 10:00 p.m. (AEEGSI, 2009).

[9] Many technical reports and contributions in the literature show that this quota ranges between 30% and 50%. See as an example Ciabattoni *et al.* (2014), Kastel and Gilroy-Scott (2015).

[10] The production input for photovoltaic production (i.e. solar radiations) is for free, and marginal production costs for the photovoltaic power plant can be considered negligible and equal to zero (Tveten *et al.*, 2013; Mercure and Salas, 2012).

[11] This assumption is necessary in order to guarantee convergence (Dixit and Pindyck, 1994).

implies that, starting from v_0, the random position of the selling price $v(t)$ $(t > 0)$ has a lognormal distribution, with mean $\ln v_0 + (\gamma - \frac{1}{2}\sigma^2)t$, and variance $\sigma^2 t$ which increases as we look further into the future. Yet, since the process (3) "has no memory" (i.e. it is Markovian), at any point in time the value $v(t)$, observed by the agent, is the best predictor of future prices[12].

3 The value of the PV plant

As the agent plays the role of both consumer and producer, for the rest of the paper, we call him prosumer. Once installed and connected to the local market, according to (2), the plant allows for a flexible choice between two polar cases. Whenever $v(t) > c$ the prosumer minimizes energy costs by selling to the local market the entire production, i.e. $\xi = 0$, and satisfying his demand by buying energy from the national grid. Whereas, whenever $v(t) < c$ the prosumer minimizes energy costs via a positive prosumption quota $\xi > 0$ such that $\bar{\alpha} = \xi\alpha_1$.

Then, for any $\xi \geq 0$, the present value of energy costs with the embedded flexibility to switch form self-consumption to "total" selling, is given by the solution of the following dynamic programming problems[13]:

$$\Gamma C^0(v(t); \xi, \alpha_1) = -[c - \alpha_1 v(t) + \xi\alpha_1(v(t) - c)], \qquad for \;\; v(t) < c \tag{4.1}$$

and

$$\Gamma C^1(v(t); \xi, \alpha_1) = -[c - \alpha_1 v(t)], \qquad for \;\; v(t) > c, \tag{4.2}$$

where Γ indicates the differential operator: $\Gamma = -r + \gamma v\frac{\partial}{\partial v} + \frac{1}{2}\sigma^2 v^2 \frac{\partial^2}{\partial v^2}$. The solution of the differential equations (4.1) and (4.2) is subject to the two following boundary conditions:

$$\lim_{v \to 0}\left\{C^0(v(t); \xi, \alpha_1) - \frac{(1-\xi\alpha_1)c}{r} + \frac{(1-\xi)\alpha_1 v(t)}{r-\gamma}\right\} = 0 \tag{5.1}$$

and

$$\lim_{v \to \infty}\left\{C^1(v(t); \xi, \alpha_1) - \frac{c}{r} + \frac{\alpha_1 v(t)}{r-\gamma}\right\} = 0, \tag{5.2}$$

In (5.1) the term $\frac{(1-\xi\alpha_1)c}{r} - \frac{(1-\xi)\alpha_1 v(t)}{r-\gamma}$ indicates the present value of operating costs meanwhile the prosumer uses the PV plant for self-consumption, whereas in (5.2) the term $\frac{c}{r} - \frac{\alpha_1 v(t)}{r-\gamma}$ indicates the present value of operating costs when selling the whole energy produced[14]. By the linearity of (4.1) and (4.2) and according to (5.1) and (5.2) we obtain*:*

$$C(v(t); \xi, \alpha_1) = \begin{cases} C^0(v(t); \xi, \alpha_1) = \frac{(1-\xi\alpha_1)c}{r} - \frac{(1-\xi)\alpha_1 v(t)}{r-\gamma} + \hat{A}v(t)^{\beta_1} & \text{if } v(t) < c \\ \\ C^1(v(t); \xi, \alpha_1) = \frac{c}{r} - \frac{\alpha_1 v(t)}{r-\gamma} + \hat{B}v(t)^{\beta_2} & \text{if } v(t) > c. \end{cases} \tag{6}$$

where $\beta_2 < 0$ and $\beta_1 > 1$ are the negative and the positive roots of the characteristic equation $\Phi(\beta) \equiv \frac{1}{2}\sigma^2\beta(\beta - 1) + \gamma\beta - r$ respectively. In (6), the additional terms $\hat{A}v(t)^{\beta_1}$ and $\hat{B}v(t)^{\beta_2}$

[12] We assume that the agent is price-taker, i.e. $v(t)$ is independent of α_1.

[13] A PV plant has generally a very long technical life that rages between 20 and 25 years. Then, without loss in generality, in (6) we approximate the technical life to infinite.

[14] Since a PV plant has generally a very long operating life that ranges between 20 and 30 years, without loss in generality, we calculate the present value of operating costs approximating the technical life to infinite.

represent the value of the option to switch from self-consumption to energy selling if $v(t)$ increases, and the value of the option to switch the other way round if $v(t)$ decreases, respectively. Finally, imposing the value matching and the smooth pasting conditions[15] at $v(t) = c$, we obtain the values of the constants:

$$\begin{cases} \hat{B} = \xi\alpha_1 B \equiv \xi\alpha_1 \frac{1}{(r-\gamma)} \frac{r-\gamma\beta_2}{r(\beta_2-\beta_1)} c^{1-\beta_2} \\ \hat{A} = \xi\alpha_1 A \equiv \xi\alpha_1 \frac{1}{(r-\gamma)} \frac{r-\gamma\beta_1}{r(\beta_2-\beta_1)} c^{1-\beta_1}. \end{cases} \tag{7}$$

which are always non-positive and both linear in $\xi\alpha_1$.

4 The optimal size of the plant and investment timing

We can now calculate the value of the option to invest in the plant (i.e. the ex-ante value of the plant), as well as its optimal size α_1.

The opportunity to invest must be considered with respect to the alternative that, in our case, is to satisfy the entire demand by buying energy from the national grid at the contracted price c. Then, the prosumer will invest if and only if the plant generates a payoff (in term of lower costs), greater than the *status quo*, i.e.:

$$\Delta C(v(t);\xi,\alpha_1) \equiv \frac{c}{r} - C(v(t);\xi,\alpha_1) = \begin{cases} \frac{\xi\alpha_1 c}{r} + \frac{(1-\xi)\alpha_1 v(t)}{r-\gamma} - \hat{A}v(t)^{\beta_1} & \text{if } v(t) < c \\ \\ \frac{\alpha_1 v(t)}{r-\gamma} - \hat{B}v(t)^{\beta_2} & \text{if } v(t) > c. \end{cases} \tag{8}$$

In the first line $\frac{\xi\alpha_1 c}{r}$ indicates the energy saving, $\frac{(1-\xi)\alpha_1 v(t)}{r-\gamma}$ indicates the expected revenues from selling the quota exceeding prosumption and $\hat{A}v(t)^{\beta_1}$ is the revenues generated by the option to sell the entire production to the local market. In the second line we get $\frac{\alpha_1 v(t)}{r-\gamma}$, the expected revenues from selling all the production, plus the option to go back to self-consumption.

For a given current value of the selling price $v(t)$, the prosumer's problem is to choose the optimal size by maximizing (8) with respect to α_1, net of the investment costs. The optimal size is then given by[16]:

$$\alpha_1^*(v(t)) = \arg\max\left[NPV(v(t))\right] \tag{9}$$

where $NPV(v(t)) \equiv \Delta C(v(t);\xi,\alpha_1) - I(\alpha_1)$, and $I(\alpha_1)$ is the plant's investment cost as a function of the energy produced.

About the cost $I(\alpha_1)$. Although it is in general related to the maximum power measured in kWp[17], referring to the characteristics of the plant as well as to the panels production curve, it is possible to calculate the investment cost as a function of the size of the plant (see Appendix C). In particular, we model the cost as a Cobb-Douglas, with increasing cost-to-scale, quadratic in the size α_1[18]:

[15] See Dixit and Pindyck, (1994).

[16] See Di Corato and Moretto (2011) and Moretto and Rossini (2012) for an application of this framework to a firm that decides the level of vertical integration.

[17] kWp stands for "kilowatt peak", and indicates the nominal power of the plant (or of the panel). It is calculated with respect to specific standard environmental conditions: 1000 W/m^2 light intensity, cell positioned at latitude 35° N, reaching a temperature of 25° C (International IEC standard 904-3, 1989).

[18] The sunk cost is assumed to be quadratic only for the sake of simplification. None of the results were altered if the investment cost is represented by a more general formulation $I(\alpha) = K\alpha^\delta$ where $\delta > 1$.

$$I(\alpha_1) = \frac{K}{2}\alpha_1^2. \tag{10}$$

Equation (10) captures: capital costs (i.e. panel costs, inverters and cables), on-going system-related costs (i.e. operating and maintenance costs), insurance costs etc., and converts them into a common metric α_1. Finally, the convexity of (10) captures the efficency losses caused by the system depreciation as well as the increase in maintenance costs during its production life[19].

By substituting (10) into (9) and according to Assumption 5, the first order condition gives:

$$\alpha_1^*(v(t)) = \max\left[\frac{\frac{v(t)}{(r-\gamma)}}{K},\ \bar{\alpha}\right]. \tag{11}$$

The plant's optimal size is given by the ratio between the expected discounted flow of revenues produced by an additional unit of capacity and the marginal cost of this unit. Note that, as α_1^* is a function of the current value of $v(t)$, the selling price must be sufficiently high to make it profitable to invest in a plant whose size is greater than $\overline{\alpha}$. Otherwise, by Assumption 5, the optimal choice is to set ξ such that $\alpha_1^* = \bar{\alpha}$[20].

Let's now turn to the optimal investment strategy. Denoting by $F_{SG}(v(t))$ the value of the option to invest in the plant connected to a SG, it is given by the solution of the following dynamic programming problem:

$$\Gamma F_{SG}(v(t)) = 0, \qquad \text{for } v_0 < v(t) < v^* \tag{12}$$

where v^* is the selling price that triggers the investment. The general solution is:

$$F_{SG}(v(t)) = Mv(t)^{\beta_1} \quad \text{for } v_0 < v(t) < v^* \tag{13}$$

where $\beta_1 > 1$ is the positve root of $\Phi(\beta)$ and M is a constant. On the contrary, whenever $v^* \leq v_0$ it is optimal for the prosumer to invest immediately[21].

Proceeding as previously, by imposing the value matching and the smooth pasting conditions at v^*, we can prove that:

Proposition 1 *i) if $\beta_1 < 2$ then:*

1) when $v(t) < c$ we obtain:

$$\frac{v^*}{r-\gamma} = \frac{\beta_1 - 1}{\beta_1 - 2}\left(\frac{1}{2}\bar{\alpha}K\right) + \sqrt{(\frac{\beta_1 - 1}{\beta_1 - 2})^2\left(\frac{1}{2}\bar{\alpha}K\right)^2 - \frac{\beta_1}{\beta_1 - 2}\frac{\bar{\alpha}c}{r}K} \tag{14.1}$$

whereas

2) when $v(t) \geq c$ we get:

$$v^* = c \tag{14.2}$$

ii) if $\beta_1 \geq 2$ it is never optimal to invest[22].

[19] On average a PV plant has an annual dacay rate higher than 1%. (Lorenzoni *et al.* 2009); in addition in the last five years of its life, it has a high probability to incur in outages. Ciabbattoni *et al.* (2014) record that PV module producers guarantee at least 80% of their initial performance after 20 years. These values are in accordance with those given by Jordan and Kurtz (2012) and Branker *et al.* (2011).

[20] Since the maximum prosumed quota is set to $\bar{\alpha}$, we implicitly assume that the minimum plant size is $\bar{\alpha}$. In other words, when $v(t) \to 0$, the NPV of the plant reduces to $NPV(\alpha_1) \equiv \frac{\xi\alpha_1 c}{r} - \frac{K}{2}\alpha_1^2$ and, in order the investment to be viable, it is necessary that $\xi = \frac{rK\bar{\alpha}}{c} \leq 1$.

[21] In other words, if $v^* \leq v_0$ the agent takes the investment decision according to the NPV rule and the option value to wait is null, i.e. $M = 0$.

[22] With $\beta_1 \geq 2$ and $v(t) < c$, the necessary condition for not investing is $\frac{(\beta_1-1)^2}{\beta_1(\beta_1-2)} < 2$ (see Appendix A), which is always satisfied in the numerical analysis.

Proof. See Appendix A. ■

Note that the optimal investment strategy is strongly influenced by the value of β_1. The greater β_1 the greater the option value to defer the decision to invest. In particular, since the prosumer will find it optimal to invest if and only if $v(t)$ is such that (13) equals $NPV(v(t))$, if $\beta_1 \geq 2$ the time value of the option is always greater than the intrinsic value.

To test the model's theoretical results and to better illustrate the relationship between the value of being connected to a SG, that allows the prosumer to sell totally or partially the energy produced, and the optimal plant size, in the next section we provide an empircal application. In order to do this, we calibrate the model using data related to the Italian electricity market.

5 Parameter estimations from empirical data

In this section we calibrate the model using data related to the Italian electricity market. In this calculations incentives are not taken into consideration. Let's start with the contracted energy price c and the selling price v:

- c is the buying price of energy, and it is representative of the average price paid by italian household consumers. The average basic energy price over the period 2013-2015 is about $c = 160$ €/MWh net of taxes and levies (Eurostat, 2015).

- $v(t)$ is the price at which the prosumer sells energy to the local market. This is the price paid by the local Transmission System Operator (TSO) to procure the resources needed to manage, operate an control the power system. In Italy Terna S.p.A. acts as TSO and is in charge of eliminating the intra-zonal congestions and creating energy reserve for real-time balancing of the system[23]. Since the differences in zonal prices are mainly determined by differences in transmission capacity and consumers' behavior (Gianfreda and Grossi, 2009; 2010), we adopt "Italian Zonal Prices"[24] recorded between 2010 and october 2015 as a proxy for $v(t)$. We built a dataset starting from hourly data provided by Terna, then, for each day we extracted price observations in the interval between 8 a.m. and 7 p.m., as we assumed that - on average - it can be considered as the interval of photovoltaic activity[25]. We then

[23] The Italian Power Exchange (IPEX), managed by the Italian independent system operator (Gestore dei Mercati Energetici, GME), is the exchange for electricity (and natural gas) spot trading in Italy. It enables producers, consumers and wholesale customers to enter into hourly electricity purchase and sale contracts. The take-off of the Spot Electricity Market (MPE) on 31 March 2004 ((Law 79/99, Law 240/04 and other Decrees), marked the advent of the first regulated electricity market in Italy. In the specific the MPE is organized as in other countries (Newbery, 2005; Lund *et al.*, 2012) and comprises: a) the Day-Ahead Market (MGP), where producers, wholesalers and eligible final customers may sell/purchase electricity for the next day; b) the Intra-Day Market (MI), where producers, wholesalers and final customers may modify the injection/withdrawal schedules that they have defined in the MGP; and c) the Ancillary Services Market (MSD), where Terna S.p.A. procures the dispatching services needed to manage, operate, monitor and control the power system. In this market Terna procures congestion-relieving resources and creates adequate secondary and tertiary control reserve margins (see www.gme.it).

[24] The Italian electric system is divided into different zones, among which physical energy exchanges are limited due to system security needs. These zones are grouped into: a) geographical zones; b) national virtual zones; c) foreign virtual zones; and d) market zones. Geographical zones represent a geographical portion of the national grid and are respectively classified into northern area, northern-central area, southern area, southern-central area, Sicily and Sardinia. National virtual zones identify limited production poles: Monfalcone, Rossano, Brindisi, Priolo and Foggia. Foreign virtual zones represent points where the nationa grid connects to adjoining Countries: France, Switzerland, Austria, Slovenia, BSP (a Slovenian electricity market zone, connected to IPEX by market coupling mechanisms), Corsica, and Greece. Finally market zones are aggregation of geographical and virtual zones in which energy flows respect the limits imposed by the Italian TSO.

[25] This corresponds to F1 time-of-use tariff (Ciabattoni *et al.*, 2014).

have calculated the average price within the photovoltaic interval and the average monthly seasonally adjusted price according to dayly averages. Next, we have validated the 68 monthly prices and verified that they are distributed as a Geometric Brownian Motion (GBM) by testing for the presence of unit root. In particular, following the procedure proposed by Bastian-Pinto *et al.* (2009), Chen (2012), Biondi and Moretto (2015) we modelled the price $v(t)$ as $\ln v(t) - \ln v(t-1) = a + (b-1)\ln v(t-1) + \varepsilon(t)$ where $\varepsilon(t)$ is i.i.d. $N(0, \sigma^2)$. We tested for unit roots, comparing the t statistics for the b coefficients obtained, with the critical values for the Dickey-Fuller test (Wooldridge 2000, p. 580). We are in fact testing if the coefficient b is statistically equal to 1, as the null hypothesis. If we fail to reject this, then we have evidence that the price serie follows a random walk and can be modeled as a GBM for which parameterization and discretization is well known. Running the regressions of the above equation for the geographical areas North, North-Central, South and South-Central, we get the results in Table 1a**:**

	North	North Central	South	South Central
a	0.063	0.060	0.053	0.062
b-1	-0.281	-0.223	-0.192	-0.214
t-statistics for (b-1)	-3.23	-2.85	-2.58	-2.78
p-values	0.078	0.178	0.314	0.204

Table 1a - Estimated regression parameters for four of the Italian geographical zones: North, North-Central, South and South Central.

Since the t statistics for all four series of prices are above the critical value of 10% significance for the unit root test, which is -2.57, indicates failure to statistically reject the presence of a unit root. Finally**,** if $v(t)$ is provided to be a GBM process, the volatility can be calculated by $\sigma = \sum_{i=1}^{n} \frac{(s_i - \widehat{s})^2}{n}$, where $\widehat{s}$ is the sample mean of $s(t) = \frac{\ln v(t+1)}{\ln v(t)}$ and the drift term γ can be estimated by performing the regression analysis of $s(t) = \beta t + \varepsilon(t)$ where $\beta = \gamma - \frac{\sigma^2}{2}$ and $\varepsilon(t) = \sigma(z(t+1) - z(t))$. The results are illustrated in Table 1b[26]**.**

Geographical areas	σ (%)	γ (%)
North	32.07	2.58
North- Central	30.35	2.9
South	31.12	3.64
South-Central	29.83	2.98

Table 1b - Estimated values for γ and σ for four of the Italian geographical zones: North, North-Central, South and South Central.

- For starting value ν_0 in each geographical zone we took the average yearly selling prices recorded in the time interval october 2014 - september 2015 (GME, 2015) as summarized in Table 2:

Year	**Yearly average zonal prices** (€/MWh)			
	North	North- Central	South	South-Central
Oct 2014-Sept 2015	56.87	54.53	51.66	53.43

Table 2 - Yearly averge zonal prices in in the time interval October 2014 - September 2015.

[26]Considering the observations relative to 2015, we obtain the following γs**:** 0.27% for North, -1.31% for North Central, -0.10% for South, -1.05% for South-Central**.** We will indirectly take into account the recent turndown of energy prices by performing simulations and comparative statics on γ in Section 6.

Other inputs are the following:

- T is the plant life time, equal to 20 or 25 years;
- r is the risk-adjusted discount rate. According to the Capital Asset Pricing Model (CAPM), $r = r_f + \beta(MRP)$, where MRP is the market risk premium, β measures the systematic risk and r_f is the risk free interest rate. According to Fernandez *et al.* (2011; 2013), the Italian market risk premium is about 5.0%. The risk-free interest rate is given by the interest rates on Italian Treasury Bonds (BTPs) with a maturity of 25 and 30 years, published by the Italian Department of the Treasury (Dipartimento del Tesoro), which are $r_f = 2.03\%$ and 3.04% respectively[27]. Finally, for the beta coefficient of the CAPM we consider β between 0.5 and 0.6[28]. By the above assumptions the risk-adjusted rate of return ranges between 4% and 6%[29]. We present the results for 4% and relegate the ones for 6% in Appendix C.
- For the quota of the energy demand that can be consumed by the prosumer during the photovoltaic interval, simulations are made assuming $\bar{\alpha}$ equal to 30% and 50%. The smaller value is near to actual average percentage of daily energy usage (Ciabbatoni *et al.* 2014). $\bar{\alpha} = 50\%$ is meant to consider the effect of being connected to a SG in terms of energy management[30].

Finally, to calibrate the cost function (10), we refer to the photovoltaic Levelized Cost Of Electricity ($LCOE$). $LCOE$ is based on the concept that all costs over the lifetime of an energy project are discounted to their net present value in a money unit divided by the discounted energy production in kWh. The result is a price of electricity expressed in €/kWh, which allows investors to earn their investment, operation and fuel cost back plus their cost-of-capital (Short et al. 1995; Ocampo 2009; Breyer *et al.* 2009; Kost *et al.*, 2013; Kastel and Gilroy-Scott, 2015; Reichelstein and Sahoo, 2015). We choose as reference values for $LCOE$: 180 €/MWh and 250 €/MWh [31]. Then, by assuming a degradation rate of 1% per year and taking account of the lack of economies of scale in residential PV systems (Branker *et al.*, 2011), we calculate the constant K (see Appendix B) as ilustrated in Table 3[32]:

	T (year)	K (€)	
		r=4%	r=6%
LCOE=180 €/MWh	20	4,956.03	4,192.83
	25	5,689.09	4,661.22
LCOE=250 €/MWh	20	6,883.39	5,823.38
	25	7,901.51	6,473.92

[27] http://www.dt.tesoro.it/export/sites/sitodt/modules/documenti_it/debito_pubblico/dati_statistici/Principali_tassi_di_interes

[28] This is reasonable from the point of view of a PV plant owner who will see a low correlation of his energy price with market risk. See for example Capizzani (2012) and Biondi and Moretto (2015).

[29] Our estimates for r are in line with Ciabattoni *et al.* (2014). They consider as a proxy for r the Weighted Average Cost of Capital (WACC), where the cost of debt is represented by the yield-to-maturity of long-term government bonds. They set the WACC equal to 5.00% by comparing the investment in the PV plant to a 20 year government bond and considering that the investor wants to earn by this investment a 1% more than investing in Italian Treasury Bonds.

[30] Ciabbatoni *et al.* (2014), in Table 5 suggest that energy management actions are able to empower grid agents with tools and mechanisms that optimize consumption patterns up to 50%.

[31] These values are consistent with recent contributions in the literature referred to Italy (Kost *et al.*, 2013; Ossenbrink *et al.*, 2013). Yet, as renewable energy tends to have zero marginal cost (Tveten *et al.*, 2013; Mercure and Salas, 2012), $LCOE$ for renewable energy technologies like PV are basically fixed over their lifetime (Kastel and Gilroy-Scott, 2015).

[32] Being solar irradiation one of the critical values to estimate the $LCOE$, an important determination of photovoltaic $LCOE$ is the system's location. However, since many factors impact on $LCOE$ definition, we mantain the same value for the four zones we consider.

Table 3 - Investment costs K for $r = 4\%,\ 6\%$, $T = 20, 25$ years and $LCOE = 180, 250$ €/MWh.

6 Simulations and sensitivity analysis

We perform the analysis for four geographical zones in Italy: North, North-Central, South and South-Central. First of all we are interested in calcuating both the optimal size of the plant α_1^* and the selling price v^* that triggers the investment. Table 4 below presents the results for $r = 4\%$ [33] by varying the $LCOE$, the life time T, the maximum prosumed quota $\bar{\alpha}$ and adopting as starting values v_0 for each zone the average yearly zonal electricity selling prices illustrated in Table 2[34].

The cells highlighted in blue represents the cases where the optimal trigger v^* is lower than the corrent value v_0. In this cases, the prosumer finds it optimal to invest immediately and the optimal size is given by $\alpha_1^* = \max[v_0/(r-\gamma)K,\ \bar{\alpha}]$.

LCOE=180

T	$\bar{\alpha}$	North α_1*	North v*	North Central α_1*	North Central v*	South α_1*	South v*	South Central α_1*	South Central v*
20	0,3	0,808	53,845	1,000	40,987	2,895	12,712	1,057	37,836
20	0,5	0,967	68,069	1,000	52,017	2,895	16,326	1,057	48,066
25	0,3	0,710	57,393	0,871	43,729	2,522	13,603	0,696	40,378
25	0,5	0,897	72,446	0,886	55,430	2,522	17,463	0,883	51,236

LCOE=250

T	$\bar{\alpha}$	North α_1*	North v*	North Central α_1*	North Central v*	South α_1*	South v*	South Central α_1*	South Central v*
20	0,3	0,641	62,644	0,720	47,799	2,085	14,934	0,761	44,152
20	0,5	0,807	78,899	0,799	60,479	2,085	19,162	0,797	55,929
25	0,3	0,595	66,711	0,627	50,960	1,816	15,976	0,663	47,085
25	0,5	0,748	83,875	0,741	64,386	1,816	20,490	0,739	59,565

Table 4 - $v^*$and α_1^* for the geographical zones North, North-Central, South and South-Central and r=4%.

Direct inspection of Table 4, shows that, as expected, in the South the investment size is bigger than in the other zones and the investment is currently profitable for both $LCOE = 180$ €/MWh and 250 €/MWh . Moreover, in all cases $\alpha_1^* > \bar{\alpha}$, i.e. the possibility to sell energy in the local market favours the agent to invest in a plant of bigger size if compared to the one dimensioned only on self-consumption. This result also holds when the prosumption energy quota increases.

Most important, we observe that there exists a positive relationship between α_1^* and v^*. To invest in a greater size, the prosumer waits longer to be sure that the investment is profitable. Furthermore, if on one hand an increase in $LCOE$, generates an increase in the investment timing, on the other hand, this results in a reduction of the plant size. Intuitively, higher $LCOE$ implies a higher investment cost that in turn determine a generalized investment delay. This delay can be reduced by reducing the plant size. The same effect is observed increasing the plant's useful life T: increasing T, *ceteris paribus*, the plant size decreases and the selling price that triggers the investment increases (i.e. the agent waits longer to invest). Summarising these results we get:

Remark 1 *An improvement in household energy management induces the investor to choose a bigger size plant, whereas an increase in the plant useful life reduces the optimal size. In both of the circumstances, though, the option value to wait for more information to come increases and this in turn results in an increase of the investment profitability.*

[33] Simulations results for $r = 6\%$ are in Appendix C.

[34] In all of our simulations the constraint $\xi = \frac{rK\bar{\alpha}}{c} \leq 1$ is always satisfied and $\beta_1 < 2$.

Tables 5 and 6 present some comparative statics with respect to different levels of the uncertainty over the selling price $v(t)$ for two principal geographical areas: North and South. The cells highlighted in yellow represent the cases where $v^* = c$, and the optimal size is $\alpha_1^* = c/(r-\gamma)K$.

Two important results emerge. First, in line with the Real Option Theory, the greater the uncertainty the greater the option value to wait (i.e. v^* increases). However, a higher uncertainty has a negative effect on the plant size (i.e. α_1^* decreases).

NORTH								
LCOE=180			σ					
			30%		35%		40%	
	T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
	20	0,30	0,764	130,787	0,729	124,897	0,705	120,693
	20	0,50	0,913	156,443	0,885	151,616	0,865	148,086
	25	0,30	0,720	135,262	0,689	129,486	0,667	125,348
	25	0,50	1,981	160,000	0,835	156,759	0,817	153,445
LCOE=250			σ					
			30%		35%		40%	
	T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
	20	0,30	0,618	147,056	0,596	141,723	0,580	137,859
	20	0,50	1,637	160,000	1,637	160,000	1,637	160,000
	25	0,30	0,582	151,780	0,562	146,683	0,548	142,974
	25	0,50	1,426	160,000	1,426	160,000	1,426	160,000

Table 5 - Optimal size α_1^* and optimal trigger v^* in the North for r =4%, T=20, 25 years, $LCOE$=180, 250 €/MWh, $\gamma = 2.58\%$ and different values of $\overline{\alpha}$ and σ.

SOUTH								
LCOE=180			σ					
			30%		35%		40%	
	T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
	20	0,30	2,895	51,660	2,895	51,660	2,895	51,660
	20	0,50	2,895	51,660	2,895	51,660	2,895	51,660
	25	0,30	2,522	51,660	2,522	51,660	2,522	51,660
	25	0,50	2,522	51,660	2,522	51,660	2,522	51,660
LCOE=250			σ					
			30%		35%		40%	
	T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
	20	0,30	2,085	51,660	2,085	51,660	2,085	51,660
	20	0,50	2,085	51,660	2,085	51,660	2,085	51,660
	25	0,30	1,816	51,660	1,816	51,660	1,816	51,660
	25	0,50	1,816	51,660	1,816	51,660	1,816	51,660

Table 6 - Optimal size α_1^* and optimal trigger v^* in the South for r =4%, T=20, 25 years, $LCOE$=180, 250 €/MWh, $\gamma = 3.64\%$ and different values of $\overline{\alpha}$ and σ.

The intution behind this result stem from the balancing effect of the positive relationship between α_1^* and v^*.Since an increase in uncertainty increases the value of postponing the investment and thus expectations for higher costs coverage, in order to accelarate investment the prosumer may decide to install a smaller size plant, that requires a lower investment cost. This effect is magnified for higher $LCOE$s: in other words, *ceteris paribus*, the greater $LCOE$ the smaller the plant size and the greater the investment deferral.

A second interesting result regards the difference in terms of investment decision between North and South. In all of the cases we investigate, the optimal price that triggers the investment in the South is always smaller than the one in the North (Table 6). In particular, in the South the investment is profitable at the current price v_0 for any σ. As an example when $\bar{\alpha} = 0.3$, $\sigma = 30\%$, $T = 20$, the optimal price that triggers the investment is $v^*(South) = v_0 = 51.60$ €/MWh whrereas in the North $v^*(North) = 130.78$ €/MWh. In the South the prosumer invests immediately and chooses a bigger size plant than in the North, i.e. $\alpha_1^*(S) > \alpha_1^*(N)$.

Tables 7 and 8 report the results for α_1^* and v^* for differen values of γ, in the North and South respectively. In order to take into consideration the recent downturn in electricity prices due to the severe reduction of the oil price, we consider $\gamma = 0\%, 1\%$ and 3%.

North

LCOE=180

		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	v*	α_1*	v*	α_1*	v*
20	0,3	0,807	160,000	0,866	128,801	1,147	56,870
20	0,5	0,807	160,000	1,065	158,272	1,147	56,850
25	0,3	0,703	160,000	0,799	136,331	1,000	56,870
25	0,5	0,703	160,000	0,937	160,000	1,000	56,870

LCOE=250

		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	v*	α_1*	v*	α_1*	v*
20	0,3	0,581	160,000	0,713	147,257	0,826	56,870
20	0,5	0,581	160,000	0,775	160,000	0,826	56,870
25	0,3	0,506	160,000	0,656	155,542	0,720	56,870
25	0,5	0,506	160,000	0,675	160,000	0,736	58,170

Table 7 - Optimal size α_1^* and optimal trigger v^* in the North for r=4%, T=20 and 25 years, $LCOE$=180 and 250 €/MWh, $\sigma = 32.07\%$ and different values of $\overline{\alpha}$ and γ.

South

LCOE=180

		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	v*	α_1*	v*	α_1*	v*
20	0,3	0,807	160,00	0,875	130,120	1,042	51,66
20	0,5	0,807	160,00	1,073	159,509	1,042	51,66
25	0,3	0,703	160,00	0,806	137,644	0,908	51,66
25	0,5	0,703	160,00	0,937	160,000	0,908	51,66

LCOE=250

		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	v*	α_1*	v*	α_1*	v*
20	0,3	0,581	160,00	0,719	148,544	0,751	51,66
20	0,5	0,581	160,00	0,775	160,000	0,794	54,667
25	0,3	0,506	160,00	0,661	156,793	0,654	51,66
25	0,5	0,506	160,00	0,675	160,000	0,737	58,244

Table 8 - Optimal size α_1^* and optimal trigger v^* in the South for r=4%, T=20 and 25 years, $LCOE$=180 and 250 €/MWh, $\sigma = 31.12\%$ and different values of $\overline{\alpha}$ and γ.

As expected, the effect of γ on the optimal investment strategy is neat: when γ decreases, the prosumer waits longer before investing, and at the time he undertakes the investment he will install a smaller size plant. Yet, the effect of γ does not differ significantly in the North and in the South. In both the zones when $\gamma = 0$ we obtain $v^* = c = 160$ €/Mwh. In other words, if the selling price fluctuates around the current value v_0 the investment decision depends solely on σ. Ultimately, the investment becomes profitable when the selling price equals the buying price. Summarizing the results we can say that:

Remark 2 *The greater the uncertainty the higher, ceteris paribus, the delay in undertaking the investment and the smaller the plant size (except in the South where the current value of the selling price makes the investment already profitable). Furthermore, if the prosumer has expectations on a progressive decrease in the selling price, he reduces the plant size and consequently defers longer the investment.*

7 The value of being connected to a smart grid

We conclude calculating the contribution of the SG on the total value of the plant. This can be done by comparing (13) to the value of a plant in absence of the option to decide whether and when to sell the energy produced[35]. In this case the system looks like the new Italian energy contract scheme known as "Scambio sul Posto" (Net Metering), where the prosumer gets credits only for the value of the excess of electricity fed into the grid over a time period[36]. Denoting by $F_{NM}(v_0)$ the values of a PV plant under the Net Metering system, in Table 9 and10 we report $F_{SG}(v_0)$, the ratio $F_{SG}(v_0)/F_{NM}(v_0)$ and the expetected time to invest $E(\tau^*)$, for a plant of 3 KWp capacity[37].

	T	$\overline{\alpha}$	North		
			F_{SG}	F_{SG}/F_{NM}	$E(\tau^*)$
LCOE=180	20	0,3	7.130,0019	1,0800	0
	25	0,3	5.245,2151	1,0918	0,27
LCOE=180	20	0,5	8.238,8036	1,1383	5,24
	25	0,5	5.612,3739	1,1645	7,05
LCOE=250	20	0,3	6.600,8071	1,1121	2,82
	25	0,3	4.558,1976	1,1311	4,65
LCOE=250	20	0,5	6.745,0112	1,2155	9,54
	25	0,5	4.471,7202	1,2702	11,32

Table 9 - Investment value in Euros of PV plants connected to a SG, investment value increase due to the connection to a SG and expected time to invest in the North of Italy for r=4% and different LCOE, T and $\overline{\alpha}$.

	T	$\overline{\alpha}$	South		
			F_{SG}	F_{SG}/F_{NM}	$E(\tau^*)$
LCOE=180	20	0,3	27.640,5317	1,0065	0
	25	0,3	23.480,2470	1,0077	0
LCOE=180	20	0,5	28.172,6316	1,0123	0
	25	0,5	23.397,0010	1,0148	0
LCOE=250	20	0,3	25.833,3774	1,0097	0
	25	0,3	21.673,0927	1,0116	0
LCOE=250	20	0,5	24.715,2153	1,0196	0
	25	0,5	19.939,5847	1,0244	0

[35] This is equivalent to eliminate Assumption 2. The agent cannot use the information received on the selling price in order to decide how to allocate his production between prosumption and sale.

[36] In the specific, the publicly-owned company playing a central role in promotion, support and development of renewable sources in Italy (GSE) pays the agent the minimum between the quantity of energy withdrawn from the national grid valuated at the national price and the quantity of power injected into the grid valuated at the hourly zonal price (GSE, 2014).

[37] A 3 KWp plant produces on average in the North of Italy about 3,300 KWh/y, whereas in the South due to more favorable conditions produces on average 4,500 KWh/y (www.fotovoltaicoenergia.com). The average installed power in Italy is 3 KWp and this installed power can satisfy the average demand of a 4 people household (http://www.fotovoltaiconorditalia.it/idee/impianto-fotovoltaico-3-kw-dimensioni-rendimenti.).

Table 10 - Investment value in Euros of PV plants connected to a SG, investment value increase due to the connection to a SG and expected time to invest in the South of Italy for r=4% and different LCOE, T and $\overline{\alpha}$.

The remarkable result is that in the North being connected to a SG increases by about 10-30% the investment's value and this quota increases (as expected) as energy savings increase. In the South this quota is consistently smaller (ranging from 0.6% to 2%). In the South the contribution to the overall investment's value is negligible if compared to the NPV. This is simply due to the fact that, at the current energy price v_0, in the South it is already valuable to invest in a PV plant without considering any type of managerial flexibility, i.e. $E(\tau^*) = 0$. Whereas, in the North, it is always optimal to wait to invest except when $LCOE = 180$ €$/MWh$, $\overline{\alpha} = 0.3$ and $T = 20$ years. As a consequence, in the North most of the plant's value is captured by the flexibility embedded in the option to switch between the two regimes. That is: a) the agent can self-consume part of the energy produced and satisfy the rest of the demand by buying energy from the national grid; or b) he can totally selling the energy produced in the local balancing market at its market price and satisfy his demand by buying energy from the national provider.[38]

Remark 3 *In the North the NPV of a PV plant, though positive, is still very low. Further, the flexibility introduced by connecting the plant to a SG, it would greatly increase its value at the cost of deffering the investment decision.*

8 Conclusions

The development of distributed power plants, in the future, shall be managed through a system that allows for a better integration of renewable energy plants, calling for private actions helping grid management.

In this paper we modelled the investment decision of a prosumer in a PV plant trying to attract the money value of being connected to a SG. Our findings show that the possibility to sell energy in the local market favours the agent to invest in a plant of bigger size if compared to the one needed for self-consumption and there exists a positive relation between the optimal size and the optimal investment timing. The greater the variance over selling price the shorter the delay in undertaking the investment and the smaller the plant size. In other words, the agent might enter the market relatively earlier, but with smaller size plants. In this respect, it is reasonable to expect that in those area where the grid suffers from congestions or high degrees of production unpredictability, the involvement of the prosumers in the grid management might push investments, making agents do an extra effort to provide the grid with private services on response to price signals: in these zones, actually, the prosumer expects to be called more frequently to contribute to grid management i.e. higher prices/higher volatility are expected. The possibility to sell energy to the local market via the SG, increases the investment value. The connection to the SG, in turn, increases managerial flexibility: the agent can optimally exercise the option to decide the prosumption quota and switch from prosumption to production, thus increasing the investment value.

As far as further research is concerned, to complicate the analysis, and better capture the value of time in the investment decision, it is possible to consider the buyng price of energy c as a stochastic variable. If expectations on price c enter the analysis, they might strongly affect the decisions whether or not to undertake the investment and on the investment timing. On the

[38] Similar results are obtained with $r = 6\%$. In this case a higher cost of capital reduces the overall value of the project andincreases the value part of the project due to the flexibility (See Appendix C).

one hand, if the energy price c is expected to incraese in the future, the opportunity to invest, ceteris paribus, becomes more valuable, due to increasing savings obtained by prosumption; on the other hand, if price drops are expected, the prosumer might decide to wait and see future price realizations – and not to kill the waiting to invest option.

A Appendix A

A) Let consider first the case $v(t) < c$. From (9), (10) and substituting $\alpha_1^* > \bar{\alpha}$, the NPV of the project is:

$$\begin{aligned} NPV(v(t)) &= \alpha_1^* \frac{v(t)}{r-\gamma} - \overline{\alpha}(\frac{v(t)}{r-\gamma} - \frac{c}{r}) - (\overline{\alpha}\hat{A}v(t)^{\beta_1} + \frac{K}{2}(\alpha_1^*)^2) \\ &= \frac{c}{r}\overline{\alpha} + \frac{v(t)}{r-\gamma}\left(\frac{1}{2K}(\frac{v(t)}{r-\gamma}) - \overline{\alpha}\right) - \overline{\alpha}\hat{A}v(t)^{\beta_1} \end{aligned}$$

with $NPV(0) = \frac{c}{r}\overline{\alpha}$ and $NPV'(0) = -\frac{1}{r-\gamma}\overline{\alpha}$. In order to determine the optimal trigger v^*, we impose the following matching value and smooth pasting conditions:

$$Mv^{*\beta_1} = \frac{1}{2K}(\frac{v^*}{r-\gamma})^2 - \overline{\alpha}(\frac{v^*}{r-\gamma} - \frac{c}{r}) - \overline{\alpha}\hat{A}v^{*\beta_1} \tag{A.1}$$

$$M\beta_1 v^{*\beta_1 - 1} = \frac{1}{K}(\frac{v^*}{r-\gamma})\frac{1}{r-\gamma} - \overline{\alpha}\frac{1}{r-\gamma} - \overline{\alpha}\hat{A}\beta_1 v^{*\beta_1 - 1} \tag{A.2}$$

These can be rearranged as follows:

$$\begin{aligned} Mv^{*\beta_1} &= \frac{1}{2K}(\frac{v^*}{r-\gamma})^2 - \overline{\alpha}(\frac{v^*}{r-\gamma} - \frac{c}{r}) - \overline{\alpha}\hat{A}v^{*\beta_1} \\ Mv^{*\beta_1} &= \frac{1}{\beta_1 K}(\frac{v^*}{r-\gamma})\frac{v^*}{r-\gamma} - \frac{\overline{\alpha}}{\beta_1}\frac{v^*}{r-\gamma} - \overline{\alpha}\hat{A}v^{*\beta_1} \end{aligned}$$

Let $y = \frac{v^*}{r-\gamma}$,we can reduce the above expression as:

$$y^2(\frac{\beta_1 - 2}{\beta_1}) - 2(\frac{\beta_1 - 1}{\beta_1})K\overline{\alpha}y + 2\overline{\alpha}\frac{c}{r}K = 0$$

Let's rearrange it as:

$$y^2 - 2K\overline{\alpha}y(\frac{\beta_1 - 1}{\beta_1 - 2}) + \frac{\beta_1}{\beta_1 - 2}2K\overline{\alpha}\frac{c}{r} = 0 \tag{A.3}$$

Define now

$$J(y) = y^2 - 2K\overline{\alpha}y(\frac{\beta_1 - 1}{\beta_1 - 2}) + \frac{\beta_1}{\beta_1 - 2}2K\overline{\alpha}\frac{c}{r} \tag{A.4}$$

The function $J(y)$ is convex in y and $J(0) = \frac{\beta_1}{\beta_1 - 2}2\overline{\alpha}\frac{c}{r}K$. The minimum $y^{\min}$ solves the following equation:

$$y^{\min} = (\frac{\beta_1 - 1}{\beta_1 - 2})K\overline{\alpha}$$

Note that for $\beta_1 < 2$ we have $y^{\min} < 0$ and $J(0) < 0$, this implies that we have a negative and positive solution to the equation above. The optimal one is the positive solution:

$$\frac{v^*}{r-\gamma} = \frac{\beta_1 - 1}{\beta_1 - 2}\left(\frac{1}{2}\bar{\alpha}K\right) + \sqrt{(\frac{\beta_1 - 1}{\beta_1 - 2})^2\left(\frac{1}{2}\bar{\alpha}K\right)^2 - \frac{\beta_1}{\beta_1 - 2}\frac{\bar{\alpha}c}{r}K} \tag{A.5}$$

For $\beta_1 \geq 2$ we have $y^{\min} > 0$ and $J(0) \geq 0$, this implies that we may have: 1) two solutions, namely $0 \leq y_1 < y_2$ where the first should be the optimal one, 2) one solution, $0 < y_1$ or 3) no solution at all. Let's check the condition for $J(y^{\min}) \geq 0$. By (A.4) it follows that:

$$J(y^{\min}) = K\overline{\alpha}(\frac{\beta_1 - 1}{\beta_1 - 2})\left[-K\overline{\alpha}(\frac{\beta_1 - 1}{\beta_1 - 2}) + \frac{\beta_1}{\beta_1 - 1}2\frac{c}{r}\right]$$

is positve if:

$$\frac{c}{r} - \frac{(\beta_1 - 1)^2}{\beta_1(\beta_1 - 2)}\frac{K}{2}\overline{\alpha} > 0 \tag{A.6}$$

Then, since at $\overline{\alpha}$, $\frac{rK\bar{\alpha}}{c} \leq 1$ condition (A.6) always holds true if $\frac{(\beta_1-1)^2}{\beta_1(\beta_1-2)} < 2$.

B) Let consider now the case where $v(t) > c$. Form (9), (10) and substituting $\alpha_1^* > \bar{\alpha}$, we get:

$$\begin{aligned} NPV(v(t)) &= \alpha_1^*\frac{v(t)}{r-\gamma} - \overline{\alpha}\hat{B}v(t)^{\beta_2} - \frac{K}{2}(\alpha_1^*)^2 \\ &= (\frac{v(t)}{r-\gamma})^2\frac{1}{2K} - \overline{\alpha}\hat{B}v(t)^{\beta_2} \end{aligned} \tag{A.7}$$

where the first term $(\frac{v(t)}{r-\gamma})^2\frac{1}{2K}$ dominates as $v(t) \to \infty$. Then, imposing the matching value and smooth pasting conditions we get:

$$Mv^{*\beta_1} = (\frac{v^*}{r-\gamma})^2\frac{1}{2K} - \overline{\alpha}\hat{B}v^{*\beta_2} \tag{A.8}$$

$$M\beta_1 v^{*\beta_1} = (\frac{v^*}{r-\gamma})^2\frac{1}{K} - \overline{\alpha}\hat{B}\beta_2 v^{*\beta_2} \tag{A.9}$$

Setting $y = \frac{v^*}{r-\gamma}$, and substituting B we can reduce the above expression as:

$$(y)^2\left[\frac{1}{K} + 2\overline{\alpha}c(r-\gamma)^{\beta_2-1}\frac{r-\gamma\beta_2}{r(\beta_1-2)}y^{\beta_2-2}\right] = 0 \tag{A.10}$$

which admits a positive root only if $\beta_1 < 2$. However in this case $Mv(t)^{\beta_1}$ will be always below the $NPV(v(t))$ and it will be optimum to invest at c. On the contrary if $\beta_1 \geq 2$, the option to invest $Mv(t)^{\beta_1}$ will never be exercised.

B Appendix B

$LCOE$ calculations, escluding Feed in Tariff and other subsidies, is given by:

$$\int_0^T C(t)e^{-rt}dt = \int_0^T LCOE(t) \times E(t)e^{-rt}e \tag{B.1}$$

where $LCOE(t)$ is €/MWh and $E(t)$ is the annual electricity output. On the left hand side of (B.1), the net costs include initial investment (via equity and/or debt), operating and maintenance costs and the insurance costs. In particular, the energy generated in a given year is the energy output S at $t = 0$, multiplied by a degradation factor e^{-dt} which decreases the energy produced with time. Then, defining $I = \int_0^T C(t)e^{-rt}dt$ and assuming the $LCOE$ constant over time we get:

$$I = \frac{LCOE \times S}{r+d}(1 - e^{-(r+d)T}) \tag{B.2}$$

where the energy output S can be determined by multiplying the system size in kWp by the local solar insolation that takes capacity factor into account in the units: kWh/kWp/year. This value is determined by multiplying the number of days in the year by average number of hours per year the solar PV system operates by system size to get the final units of kWh/year.

Since residential PV systems tend to have the more expensive $LCOE$ due to lacking economies of scale (Branker et al. 2011), we can assume that $LCOE \times S = f(S)$,with $f'(S) > 0$ and $f''(S) > 0$. In particular, since $LCOE$ that we find in the literature incorporates a decay rate of 1%, we calibrate the constant K by setting $S = 1$ MWh and $d = 0$ in (B.2), i.e.:

$$K = 2\frac{LCOE}{r}(1 - e^{-rT}) \tag{B.3}$$

C Appendix C

In what follows we report simulations results for $r = 6\%$.

LCOE=180

T	$\overline{\alpha}$	North α_1*	North v*	North Central α_1*	North Central v*	South α_1*	South v*	South Central α_1*	South Central v*
20	0,3	0,746	107,038	0,740	96,149	0,702	69,420	0,738	93,491
20	0,5	0,914	131,061	0,908	118,036	0,874	86,517	0,907	114,835
25	0,3	0,701	111,743	0,695	100,425	0,661	72,713	0,694	97,658
25	0,5	0,856	136,447	0,851	122,963	0,822	90,452	0,850	119,644

LCOE=250

T	$\overline{\alpha}$	North α_1*	North v*	North Central α_1*	North Central v*	South α_1*	South v*	South Central α_1*	South Central v*
20	0,3	0,613	122,106	0,609	109,862	0,583	80,061	0,608	106,860
20	0,5	0,744	148,183	0,741	133,725	0,722	99,169	0,740	130,153
25	0,3	0,575	127,258	0,571	114,562	0,548	83,762	0,570	111,445
25	0,5	0,695	153,949	0,693	139,026	0,678	103,527	0,692	135,332

Table 1A - $v^*$and α_1^* for the geographical zones North, North-Central, South and South-Central for r=6%.

NORTH

LCOE=180

T	$\overline{\alpha}$	σ 30% α_1*	30% v*	35% α_1*	35% v*	40% α_1*	40% v*
20	0,30	0,759	108,861	0,731	104,854	0,711	101,931
20	0,50	0,925	132,640	0,901	129,152	0,883	126,566
25	0,30	0,712	113,540	0,687	109,586	0,669	106,693
25	0,50	0,865	137,931	0,845	134,648	0,829	132,205

LCOE=250

T	$\overline{\alpha}$	σ 30% α_1*	30% v*	35% α_1*	35% v*	40% α_1*	40% v*
20	0,30	0,622	123,810	0,603	120,055	0,589	117,288
20	0,50	0,750	149,405	0,737	146,693	0,726	144,655
25	0,30	0,582	128,894	0,566	125,282	0,554	122,611
25	0,50	0,700	155,015	0,689	152,646	0,681	150,858

Table 2A - Optimal size α_1^* and optimal trigger v^* in the North for r =6%, T=20 and 25 years, LCOE=180, 250 €/MWh, $\gamma = 2.58\%$ and different values of $\overline{\alpha}$ and σ.

SOUTH							
LCOE=180		σ					
		30%		35%		40%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,30	0,705	69,793	0,690	68,283	0,678	67,113
20	0,50	0,878	86,851	0,864	85,496	0,853	84,437
25	0,30	0,664	73,084	0,651	71,585	0,640	70,422
25	0,50	0,825	90,769	0,813	89,484	0,804	88,477
LCOE=250		σ					
		30%		35%		40%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,30	0,585	80,417	0,575	78,975	0,566	77,851
20	0,50	0,724	99,434	0,716	98,354	0,709	97,504
25	0,30	0,550	84,107	0,541	82,710	0,534	81,620
25	0,50	0,679	103,761	0,673	102,809	0,668	102,058

Table 3A - Optimal size α_1^* and optimal trigger v^* in the South for r=6%, T=20 and 25 years, $LCOE$=180 and 250 €/MWh, $\gamma = 3.64\%$ and different values of $\overline{\alpha}$ and σ.

North							
LCOE=180							
		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,3	0,636006	160,000	0,763	160,000	0,726	91,364
20	0,5	0,636006	160,000	0,763	160,000	0,896	112,751
25	0,3	0,572096	160,000	0,687	160,000	0,683	95,521
25	0,5	0,572096	160,000	0,687	160,000	0,841	117,603
LCOE=250							
		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,3	0,458	160,000	0,550	160,000	0,599	104,732
20	0,5	0,458	160,000	0,550	160,000	0,734	128,254
25	0,3	0,412	160,000	0,494	160,000	0,563	109,338
25	0,5	0,412	160,000	0,494	160,000	0,688	133,528

Table 4A- Optimal size α_1^* and optimal trigger v^* in the North for r=6%, T=20 and 25 years, $LCOE$=180 and 250 €/MWh, $\sigma = 32.07\%$ and different values of $\overline{\alpha}$ and γ.

South							
LCOE=180							
		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,3	0,636	160,000	0,763	160,000	0,731	91,924
20	0,5	0,636	160,000	0,763	160,000	0,900	113,244
25	0,3	0,572	160,000	0,687	160,000	0,687	96,075
25	0,5	0,572	160,000	0,687	160,000	0,844	118,068
LCOE=250							
		γ					
		0%		1%		3%	
T	$\overline{\alpha}$	α_1*	**v***	α_1*	**v***	α_1*	**v***
20	0,3	0,458	160,000	0,550	160,000	0,603	105,260
20	0,5	0,458	160,000	0,550	160,000	0,736	128,641
25	0,3	0,412	160,000	0,494	160,000	0,566	109,848
25	0,5	0,412	160,000	0,494	160,000	0,689	133,867

Table 5A- Optimal size α_1^* and optimal trigger v^* in the South for r=6%, T=20 and 25 years, $LCOE$=180 and 250 €/MWh, $\sigma = 31.12\%$ and different values of $\overline{\alpha}$ and γ.

	T	$\overline{\alpha}$	North		
			F_{SG}	F_{SG}/F_{NM}	$E(\tau^*)$
LCOE=180	20	0,3	492,9272	1,1303	14
	25	0,3	442,5056	1,1473	15,28
LCOE=180	20	0,5	470,8320	1,2517	18,89
	25	0,5	413,4568	1,2970	19,80
LCOE=250	20	0,3	348,5938	1,1947	17,29
	25	0,3	309,1064	1,2252	18,23
LCOE=250	20	0,5	306,8921	1,4462	21,67
	25	0,5	262,2215	1,5652	22,53

Table 6A - Investment value in Euros of PV plants connected to a SG, investment value increase due to the connection to a SG and expected time to invest in the North of Italy for r=6% and different LCOE, T and $\overline{\alpha}$.

	T	$\overline{\alpha}$	South		
			F_{SG}	F_{SG}/F_{NM}	$E(\tau^*)$
LCOE=180	20	0,3	4.531,7428	1,0748	6,13
	25	0,3	3.260,2761	1,0842	7,09
LCOE=180	20	0,5	4.511,4939	1,1412	10,69
	25	0,5	3.154,9699	1,1658	11,62
LCOE=250	20	0,3	3.830,4529	1,1101	9,08
	25	0,3	2.727,2775	1,1268	10,02
LCOE=250	20	0,5	3.401,9192	1,2466	13,52
	25	0,5	2.295,7204	1,3110	14,42

Table 7A - Investment value in Euros of PV plants connected to a SG, investment value increase due to the connection to a SG and expected time to invest in the South of Italy for r=6% and different LCOE, T and $\overline{\alpha}$.

References

[1] AEEGSI, DCO 37/09 - Public consultation November 19th, 2009 (Ipotesi di incremento della potenza prelevabile nelle ore a basso carico per utenze domestiche con rilevazione dei prelievi per fasce orarie)

[2] AEEGSI n. 522/2014/r/eel (Disposizioni in materia di dispacciamento delle fonti rinnovabili non programmabili a seguito della sentenza del Consiglio di Stato - Sezione Sesta - 9 giugno 2014, n. 2936)

[3] Biondi T., Moretto M., (2015). Solar Grid Parity dynamics in Italy: A real option approach. *Energy*, 80, 293-302.

[4] Branker K., Pathak J.M., Pearce J.M., (2011). A review of solar photovoltaic levelized cost of electricitity. *Renewable and Sustainable Energy Reviews*, 15, 4470-4482.

[5] Breyer C., Gerlach A., Müller J., Behacker H., Milner, A., (2009). Grid-parity analysis for EU and US regions and market segments dynamics of grid-parity and dependence on solar irradiance, local electricity prices and PV progress ratio. In Proceedings of 24th European photovoltaic solar energy conference, 4492-4500.

[6] Capizzani F., (2012). La valutazione del Fair Value degli assets fotovoltaici e l'applicazione del metodo reddituale-finanziario nella prospettiva delle SGR-Società di Gestione del Risparmio. Mimeo. Università degli Studi di Bologna, 120-121.

[7] Capuder T., Mancarella P., (2014). Techno-economic and environmental modelling and optimization of flexible distributed multi-generation options, *Energy*, vol. 71, 516-533.

[8] Chen P., (2012). The investment strategies for a dynamic supply chain under stochastic demands. *Int. J. Production Economics*, 139, 80-89.

[9] Ciabattoni L., Grisostomi M., Ippoliti G., Longhi S., (2014). Fuzzy logic home energy consumption modeling for residential photovoltaic plant sizing in the new Italian scenario. *Energy*, 74 (1), 359-367

[10] D'Alpaos C., Dosi C., Moretto M., (2006). Concession Length and Investment Timing Flexibility", *Water Resources Research*, 42, W02404, 1-4.

[11] D'Alpaos C., Moretto M., Valbonesi P., Vergalli S., (2013). Time Overruns as Opportunistic Behavior in Public Procurement, *Journal of Economics*, vol. 110 (1), 25-43.

[12] Da Silva Goncalves P., Ilic D., Karnouskos S., (2014). The impact of smart grid prosumer grouping on forecasting accuracy and its benefits for local electricity market trading. Smart Grid, IEEE Transactions on 5.1, 402-410.

[13] Di Corato L., Moretto M., (2011). Investing in biogas: timing, technological choice and the value of flexibility from inputs mix, *Energy Economics*, 33 (6), 1186-1193

[14] Dixit A., Pindyck R.S., (1994). *Investment under Uncertainty.* Princeton University Press: Princeton.

[15] Eurostat, (2015). Data available on http://ec.europa.eu/eurostat/statistics-explained/index.php/File:Electricity_prices_for_household_consumers,_second_half_2014_%28%C2%B9 [last accessed on 2.9 2015].

[16] Fernandes B., Cunha J., Ferreira P., (2011). The use of real options approach in energy sector investments, *Renewable and Sustainable Energy Reviews*, 15, 4491– 4497

[17] Fernandez P., Aguirreamalloa J., Corres L., (2011). Market risk premium used in 56 countries in 2011: a survey with 6,014 answers. IESE Working Paper n. 920. May 2011.

[18] Fernandez P., Aguirreamalloa J., Corres L., (2013). Market Risk Premiun used in 82 countries in 2012: a survey with 7,192 answers. IESE Working Paper n. 1059-E. January 2013.

[19] Fleten S.E., Maribu K.M. and Wangensteen I. (2007) Optimal investment strategies in decentralized renewable power generation under uncertainty. *Energy*, 32, 803–815

[20] Gianfreda A., Grossi L., (2009). Zonal price analysis of the Italian wholesale electricity market. EEM 2009 - 6th International Conference on the European Energy Market 3.

[21] Gianfreda A., Grossi L., (2010). Forecasting Italian electricity zonal prices with exogenous variables. *Energy Economics,* 34 (6), 2228–2239.

[22] GME, (2015). Data available on http://www.mercatoelettrico.org/it/Statistiche/ME/DatiSintesi.aspx [last accessed on 2.9 2015].

[23] GSE, (2013). Rapporto statistico 2012. Impianti a fonti rinnovabili, Settore elettrico available on http://www.gse.it/it/Dati%20e%20Bilanci/GSE_Documenti/osservatorio%20statistico/Rapporto%20Sta %20Settore%20Elettrico%20%20%20vers%20web%20def.pdf

[24] GSE (2014). Attuazione delle disposizioni del decreto legge 91/14 in materia di scambio sul posto [last accessed 18.8.2015], http://www.autorita.energia.it/allegati/docs/14/612-14.pdf.

[25] Hoff T.E., Wenger H.J, Farmer B.K., (1996). Distributed generation - An alternative to electric utility investments capacity. *Energy Policy*, 24 (2), 137-147.

[26] Jordan D.C., Kurtz S.R. (2013). Photovoltaic Degradation Rates— An Analytical Review. *Progress in Photovoltaics: Research and Applications*, 21 (1), 12-29.

[27] Karnouskos S., (2011). Demand side management via prosumer interactions in a smart city energy marketplace. Innovative Smart Grid Technologies (ISGT Europe), 2011 2nd IEEE PES International Conference and Exhibition on IEEE.

[28] Kitapbayev Y., Moriarty J., Mancarella P., Blochle M., (2013). A real options assessment of operational flexibility in district energy systems. In Proceedings of the 10th international conference on the European Energy Market**.**

[29] Konstantelos I., Strbac G., (2015). Valuation of flexible transmission investment options under uncertainty, *IEEE Trans Power Syst,* 30 (2), 1047–55.

[30] Kost C., Mayer J.N., Thomsen J., Hartmann N., Senkpiel C., Phillips S., Nold S., Lude S., Saa N., Schlegl T. (2013). Levilized cost of electricity renewable energy technologies. Fraunhofer Institute, study of November 2013

[31] Lorenzoni A., Bignucolo F., Bano L., Doni A., Sacco A., (2009). Il valore dell'energia fotovoltaica in Italia - rapporto per GIFI, 30 settembre 2009. Mimeo, Università degli Studi di Padova.

[32] Lund H., Andersen A.N., Ostergaard P.A., Mathiesen B.V., Connolly D., (2012). From electricity smart grids to smart energy systems- A market operation based approach and understanding. *Energy*, 42, 96-102.

[33] Majd S., Pindyck R.S., (1987). Time to Build, Option Value, and Investment Decisions, *Journal of Financial Economics*, 19, 7-27.

[34] Makrides G., Zinsser B., Schubert M., Georghiou G.E., (2013). Energy yield prediction errors and uncertainties of different photovoltaic models. *Progress in Photovoltaics: Research and Applications*, 21 (4), 500-516.

[35] Makrides G., Zinsser B., Schubert M., Georghiou G.E., (2014). Performance loss rate of twelve photovoltaic technologies under field conditions using statistical techniques. *Solar Energy*, 103, 28-42.

[36] Makrides G., Zinsser B., Norton M., Georghiou G.E., (2012) Performance of photovoltaics under actual operating conditions: chapter 9. In Fthenakis V. (ed.): "Third Generation Photovoltaics" . InTech. http://www.intechopen.com/books/third-generation-photovoltaics/performance-of-photovoltaics-under-actual-operating-conditions.

[37] Maarten W. (2012). The research agenda on social acceptance of distributed generation in smart grids: renewable as common pool resources. *Renewable and Sustainability Energy Review*, 16 (1), 822-835.

[38] Martinez Cesena E.A.M., Mancarella P., (2014). Distribution network reinforcement planning considering demand response support. In: Proceedings of the 2014 Power Systems Computation Conference, 1-7.

[39] Martinez Cesena E.A.M., Mutale J., Rivas-Davalos F., (2013). Real options theory applied to electricity generation projects: A review, *Renewable and Sustainable Energy Reviews*, 19, 573–581.

[40] Mercure J.F, Salas P., (2012). An assessement of global energy resource economic potentials. *Energy*, 46, 322–36

[41] Moretto M., Rossini G., (2012). Flexible outsourcing. *Managerial and Decision Economics*, 33 (1), 47-59.

[42] Mulder G., De Ridder F., Six D., (2010). Electricity storage for grid-connected household dwellings with PV panels. *Solar Energy*, 84, 1284-1293

[43] Ocampo M.T., (2009). How to calculate the levelized cost of energy: a simplified approach. Energy Technology Expert.

http://energytechnologyexpert.com/cost-of-power-generation/howto-calculate-the-levelized-cost-of-power-or-energy.

[44] Newbery D. (2005). Electricity Liberalisation in Britain: the Quest for a Satisfactory Wholesale Market Design. The Energy Journal, (Special issue), 43-70.

[45] Olsina F., Garcés F., Haubrich H.J., (2006). Modeling long-term dynamics of electricity markets. *Energy Policy*, 34, 1411–1433.

[46] Ossenbrink H., Huld T., Jäger Waldau A., Taylor N., (2013). Photovoltaic Electricity Cost Maps. JRC Reports – European Commission.

[47] Ottesen S.O., Tomasgard A., Fleten S.E., (2016). Prosumer bidding and scheduling in electricity markets. *Energy*, 94, 828-843.

[48] Pillai J.R., Heussen K., Ostergaard P.A., (2011). Comparative analysis of hourly and dynamic power balancing models for validating future energy scenarios. *Energy*, 36 (5), 3233-3243.

[49] Pillai G.G, Putrus G.A., Georgitsioti T., Pearsall N.M., (2014). Near-term economic benefits from grid-connected residential PV (photovoltaic) systems. *Energy,* 68, 832–843.

[50] Price S., Margolis R., (2008). Solar technologies market report. Energy Efficiency & Renewable Energy, US Department of Energy, 2010; January 2008. 1–131.

[51] Schachter J.A., Mancarella P., (2015). Demand response contracts as real options: a probabilistic evaluation framework under short-term and long-term uncertainties. *IEEE Trans Smart Grid*, 1–11.

[52] Schachter J.A., Mancarella P., (2016). A critical review of real options thinking for valuing investment flexibility in Smart Grids and low carbon energy systems., *Renewable and Sustainable Energy Reviews*, 56, 261-271.

[53] Shi L.G., Qu X J., (2011). Modeling methods for GenCo bidding strategy optimization in the liberalized electricity spot marketea state-of-the-art review. *Energy*, 36 (8), 4686-4700.

[54] Short W., Packey D., Holt T., (1995). A manual for economic evaluation of energy efficiency and renewable energy technologies. National Renewable Energy Laboratory, 1-120.

[55] Syrri A.L.A., Mancarella P., (2016). Reliability and Risk Assessment of Post-Contingency Demand Response in Smart Distribution Networks, *Sustainable Energy, Grids and Networks*, in press.

[56] Toffler, A., (1980). *The third wave*. Bantam Books, Random House, New York.

[57] Triantis A.J, Hodder J.E., (1990). Valuing flexibility as a complex option, *Journal of Finance*, 45, 549-565.

[58] Trigeorgis L. (1996). *Real Options-Managerial Flexibilitry and Strategy in Resource Allocation,* The MIT Press, Cambridge, MA.

[59] Tveten Å.G., Bolkesjø T.F., Martinsen T., Hvarnes H., (2013). Solar feed-in tariffs and the merit order effect: a study of the German electricity market, *Energy Policy,* 61, 761–70.

[60] Velik R. , Nicolay P., (2016). Energy management in storage-augmented, grid-connected prosumer buildings and neighbourhoods using a modified simulated annealing optimization. *Computers & Operations Research*, 66, 248-257.

[61] Wang X., Cai Y., and Dai C., (2014). Evaluating China's biomass power production investment based on a policy benefit real options model. *Energy*, vol.73, 751-761.

[62] Wiser R., Barbose G., Peterman C., Darghouth N., (2009). Tracking the sun – II. Installed costs of PV in the US from 1998–2008. US Department of Energy, Lawrence Livermore Berkley Laboratory, 1–50.

NOTE DI LAVORO DELLA FONDAZIONE ENI ENRICO MATTEI

Fondazione Eni Enrico Mattei Working Paper Series

Our Note di Lavoro are available on the Internet at the following addresses:

http://www.feem.it/getpage.aspx?id=73&sez=Publications&padre=20&tab=1
http://papers.ssrn.com/sol3/JELJOUR_Results.cfm?form_name=journalbrowse&journal_id=266659
http://ideas.repec.org/s/fem/femwpa.html
http://www.econis.eu/LNG=EN/FAM?PPN=505954494
http://ageconsearch.umn.edu/handle/35978
http://www.bepress.com/feem/
http://labs.jstor.org/sustainability/

NOTE DI LAVORO PUBLISHED IN 2016

ET	1.2016	Maria Berrittella, Carmelo Provenzano: An Empirical Analysis of the Public Spending Decomposition on Organized Crime
MITP	2.2016	Santiago J. Rubio: Sharing R&D Investments in Breakthrough Technologies to Control Climate Change
MITP	3.2016	W. Brock, A. Xepapadeas: Spatial Heat Transport, Polar Amplification and Climate Change Policy
ET	4.2016	Filippo Belloc: Employee Representation Legislations and Innovation
EIA	5.2016	Leonid V. Sorokin, Gérard Mondello: Sea Level Rise, Radical Uncertainties and Decision-Maker's Liability: the European Coastal Airports Case
ESP	6.2016	Beatriz Martínez, Hipòlit Torró: Anatomy of Risk Premium in UK Natural Gas Futures
ET	7.2016	Mary Zaki: Access to Short-term Credit and Consumption Smoothing within the Paycycle
MITP	8.2016	Simone Borghesi, Andrea Flori: EU ETS Facets in the Net: How Account Types Influence the Structure of the System
MITP	9.2016	Alice Favero, Robert Mendelsohn, Brent Sohngen: Carbon Storage and Bioenergy: Using Forests for Climate Mitigation
EIA	10.2016	David García-León: Adapting to Climate Change: an Analysis under Uncertainty
ESP	11.2016	Simone Tagliapietra: Exploring the Potential for Energy Efficiency in Turkey
MITP	12.2016	Gabriel Chan, Carlo Carraro, Ottmar Edenhofer, Charles Kolstad, Robert Stavins: Reforming the IPCC's Assessment of Climate Change Economics
MITP	13.2016	Kenneth Gillingham, William Nordhaus, David Anthoff, Valentina Bosetti, Haewon McJeon, Geoffrey Blanford, Peter Christenn, John Reilly, Paul Sztorc: Modeling Uncertainty in Climate Change: A Multi-Model Comparison
ET	14.2016	Paolo M. Panteghini, Sergio Vergalli: Accelerated Depreciation, Default Risk and Investment Decisions
ET	15.2016	Jean J. Gabszewicz, Marco A. Marini, Ornella Tarola: Vertical Differentiation and Collusion: Cannibalization or Proliferation?
EIA	16.2016	Enrica De Cian, Ian Sue Wing: Global Energy Demand in a Warming Climate
ESP	17.2016	Niaz Bashiri Behmiri, Matteo Manera, Marcella Nicolini: Understanding Dynamic Conditional Correlations between Commodities Futures Markets
MITP	18.2016	Marinella Davide, Paola Vesco: Alternative Approaches for Rating INDCs: a Comparative Analysis
MITP	19.2016	W. Brock, A. Xepapadeas: Climate Change Policy under Polar Amplification
ET	20.2019	Alberto Pench: A Note on Pollution Regulation With Asymmetric Information
EIA	21.2019	Anil Markandya, Enrica De Cian, Laurent Drouet, Josué M. Polanco-Martìnez, Francesco Bosello: Building Uncertainty into the Adaptation Cost Estimation in Integrated Assessment Models
MITP	22.2016	Laura Diaz Anadon, Erin Baker, Valentina Bosetti, Lara Aleluia Reis: Too Early to Pick Winners: Disagreement across Experts Implies the Need to Diversify R&D Investment
ESP	23.2016	Claudio Morana: Macroeconomic and Financial Effects of Oil Price Shocks: Evidence for the Euro Area
EIA	24.2016	Wei Jin, ZhongXiang Zhang: China's Pursuit of Environmentally Sustainable Development: Harnessing the New Engine of Technological Innovation
EIA	25.2016	Doruk İriş, Alessandro Tavoni: Tipping Points and Loss Aversion in International Environmental Agreements
ET	26.2016	Doruk İriş, Jungmin Lee, Alessandro Tavoni: Delegation and Public Pressure in a Threshold Public Goods Game: Theory and Experimental Evidence
EIA	27.2016	Stefan P. Schleicher, Angela Köppl, Alexander Zeitlberger: Extending the EU Commission's Proposal for a Reform of the EU Emissions Trading System
EIA	28.2016	Tomas Ekvall, Martin Hirschnitz-Garbers, Fabio Eboli, Aleksander Sniegocki: A Systemic Approach to the Development of a Policy Mix for Material Resource Efficiency
EIA	29.2016	Silvia Santato, Jaroslav Mysiak, Carlos Dionisio Pérez-Blanco: The Water Abstraction License Regime in Italy: A Case for Reform?
MITP	30.2016	Carolyn Fischer: Strategic Subsidies for Green Goods
MITP	31.2016	Carolyn Fischer: Environmental Protection for Sale: Strategic Green Industrial Policy and Climate Finance
ET	32.2016	Fabio Sabatini, Francesco Sarracino: Keeping up with the e-Joneses: Do Online Social Networks Raise Social Comparisons?
MITP	33.2016	Aurora D'Aprile: Advances and Slowdowns in Carbon Capture and Storage Technology Development
EIA	34.2016	Francesco Bosello, Marinella Davide, Isabella Alloisio: Economic Implications of EU Mitigation Policies: Domestic and International Effects
MITP	35.2016	Shouro Dasgupta, Enrica De Cian, and Elena Verdolini: The Political Economy of Energy Innovation

MITP	36.2016	Roberta Distante, Elena Verdolini, Massimo Tavoni: Distributional and Welfare Impacts of Renewable Subsidies in Italy
MITP	37.2016	Loic Berger, Valentina Bosetti: Ellsberg Re-revisited: An Experiment Disentangling Model Uncertainty and Risk Aversion
EIA	38.2016	Valentina Giannini, Alessio Bellucci, Silvia Torresan: Sharing Skills and Needs between Providers and Users of Climate Information to Create Climate Services: Lessons from the Northern Adriatic Case Study
EIA	39.2016	Andrea Bigano, Aleksander Śniegocki, Jacopo Zotti: Policies for a more Dematerialized EU Economy. Theoretical Underpinnings, Political Context and Expected Feasibility
ET	40.2016	Henry Tulkens: COP 21 and Economic Theory: Taking Stock
MITP	41.2016	Shouro Dasgupta, Enrica De Cian: Institutions and the Environment: Existing Evidence and Future Directions
MITP	42.2016	Johannes Emmerling, Laurent Drouet, Lara Aleluia Reis, Michela Bevione, Loic Berger, Valentina Bosetti, Samuel Carrara, Enrica De Cian, Gauthier De Maere D'Aertrycke, Tom Longden, Maurizio Malpede, Giacomo Marangoni, Fabio Sferra, Massimo Tavoni, Jan Witajewski-Baltvilks, Petr Havlik: The WITCH 2016 Model - Documentation and Implementation of the Shared Socioeconomic Pathways
MITP	43.2016	Stefano Carattini, Alessandro Tavoni: How Green are Economists?
ET	44.2016	Marco Di Cintio, Sucharita Ghosh, Emanuele Grassi: Firm Employment Growth, R&D Expenditures and Exports
ESP	45.2016	Nicola Cantore, Patrick Nussbaumer, Max Wei, Daniel Kammen: Energy Efficiency in Africa: A Framework to Evaluate Employment Generation and Cost-effectiveness
MITP	46.2016	Erin Baker, Valentina Bosetti, Ahti Salo: Finding Common Ground when Experts Disagree: Belief Dominance over Portfolios of Alternatives
MITP	47.2016	Elena Verdolini, Laura Diaz Anadón, Erin Baker, Valentina Bosetti, Lara Aleluia Reis: The Future Prospects of Energy Technologies: Insights from Expert Elicitations
MITP	48.2016	Francesco Vona, Giovanni Marin, Davide Consoli: Measures, Drivers and Effects of Green Employment: Evidence from US Local Labor Markets, 2006-2014
ET	49.2016	Thomas Longden: The Regularity and Irregularity of Travel: an Analysis of the Consistency of Travel Times Associated with Subsistence, Maintenance and Discretionary Activities
MITP	50.2016	Dipak Dasgupta, Etienne Espagne, Jean-Charles Hourcade, Irving Minzer, Seyni Nafo, Baptiste Perissin-Fabert, Nick Robins, Alfredo Sirkis: Did the Paris Agreement Plant the Seeds of a Climate Consistent International Financial Regime?
MITP	51.2016	Elena Verdolini, Francesco Vona, David Popp: Bridging the Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion?
MITP	52.2016	Johannes Emmerling, Vassiliki Manoussi, Anastasios Xepapadeas: Climate Engineering under Deep Uncertainty and Heterogeneity
MITP	53.2016	Matthew R. Sisco, Valentina Bosetti, Elke U. Weber: Do Extreme Weather Events Generate Attention to Climate Change?
MITP	54.2016	David Anthoff, Johannes Emmerling: Inequality and the Social Cost of Carbon
MITP	55.2016	Matthew Adler, David Anthoff, Valentina Bosetti, Greg Garner, Klaus Keller, Nicolas Treich: Priority for the Worse Off and the Social Cost of Carbon
EIA	56.2016	Luca Di Corato, Michele Moretto, Sergio Vergalli: Deforestation Rate in the Long-run: the Case of Brazil
ET	57.2016	Carlo Drago: Exploring the Community Structure of Complex Networks
ET	58.2016	Guiomar Martín-Herrán, Santiago J. Rubio: The Strategic Use of Abatement by a Polluting Monopoly
ET	59.2016	Philip Ushchev, Yves Zenou: Price Competition in Product Variety Networks
MITP	60.2016	Marina Bertolini, Chiara D'Alpaos, Michele Moretto: Investing in Photovoltaics: Timing, Plant Sizing and Smart Grids Flexibility